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February 22, 2018

Mr. Peter Tsirigotis, Director
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Mail Code: D205-01
109 T. W. Alexander Drive
Durham, NC 27709

Re: Leak Monitoring Data Analysis in Support of EPA's Reconsideration of the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule"

Dear Mr. Peter Tsirigotis:

The American Petroleum Institute ("API") is pleased to submit the attached information in support of EPA's reconsideration of the New Source Performance Standards ("NSPS") 40 C.F.R. Part 60 Subpart OOOOa, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule" 81 Fed. Reg. 32826 (June 3, 2016).

API represents over 625 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.8 million jobs and 8 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. Most of our members conduct oil and gas development and production operations and are directly impacted by the final rule.

Throughout the development of the 2012 oil and gas NSPS rule and its amendments in 2016, API has constructively engaged with the agency to provide operational knowledge and emissions data to inform these important rules. During this time, our objective has remained the identification of cost-effective emission control requirements that reduce VOC emissions for new sources and, as a co-benefit, also reduce methane emissions.

Following publication of the 2016 NSPS rule, API filed a petition with EPA seeking administrative reconsideration of certain requirements in the final rule. In the petition, API also included issues where changes to the rule were needed. These issues were included because, were EPA to grant reconsideration of any issues, it would be efficient for EPA to make these changes during the reconsideration process. Among the supplemental list of issues was a recommendation that the agency revisit the leak detection and repair survey frequencies for both well sites and compressor stations.

To further support this recommendation, API initiated an analysis (see attached) following data collection from companies to determine how the implementation of leak monitoring and repair programs might further inform a reduced leak survey frequency. Based on our analysis, it was determined that the initial or uncontrolled leak incidence – the number of components found leaking divided by total number of components surveyed – is significantly lower than the basis of EPA's original rule analysis. A lower initial leak incidence results in a lower baseline mass of emissions from leaks. Using EPA's cost effectiveness calculations with the lower initial leak incidence of 0.4% calculated from this analysis, it is clear that leak detection and repair programs at oil and gas well sites are not cost-effective, even under the multi-pollutant scenario EPA utilized in the rulemaking. This conservative analysis supports justification for a reduced survey frequency at well sites from semi-annual to annual. While the revised analysis results in a value greater than the agency's historical threshold of cost-effective control, the recommendation for an annual frequency is based on established industry practice for new operations. API requests that EPA review this new information as the agency reconsiders Subpart OOOOa. An electronic version of this analysis can be made available upon request.

Please contact me at toddm@api.org or 202-682-8319 with any additional questions regarding the content of this submittal.

Sincerely,

/s/

Matthew Todd

cc: Mandy Gunasekara, USEPA
Penny Lassiter, USEPA
David Cozzie, USEPA

API's Leak Monitoring and Repair Analysis in Support of EPA's Reconsideration of "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule"

81 Fed. Reg. 35826 (June 3, 2016)

1. Background

As noted in API's December 4, 2015 comments on the proposed Subpart OOOOa, EPA overestimated the environmental benefit from leak detection and repair (LDAR) programs at oil and natural gas facilities, while at the same time underestimating the costs associated with implementation of LDAR programs. As a result, EPA underestimated the cost of control ($/ton) of LDAR at well sites and compressor stations as documented in EPA's Technical Support Document (TSD) that accompanied the final Subpart OOOOa rule[1].

Since the time of the proposal of Subpart OOOOa, API member companies have established LDAR programs as part of both voluntary and regulatory efforts (e.g., Subpart OOOOa, CO, WY, CA, OH, PA, etc.). API previously shared results of some such programs in Colorado and in the Barnett Shale area of Texas in our August 2, 2016 petition for reconsideration. That data indicated an average leak incidence of 0.2% of the total components surveyed that were found leaking based on annual survey data. Similarly, Chevron submitted comments during the original rulemaking sharing their observed leak incidence range between 0.04 to 0.16%[2]. In an effort to develop a larger data set across a wider range of companies and operating areas, API conducted a blinded survey of available LDAR data to review the actual initial leak incidence being observed by operators.

2. API LDAR Survey and Initial Leak Incidence Assessment

API completed a blinded survey of operating companies that resulted in the collection of data from LDAR surveys completed using optical gas imaging (OGI) from six (6) member companies.[3] The data cover a wide range of operators and facility types at sites located in more than 14 states[4]. Only the results from the initial leak survey (the first survey) conducted at an individual

[1] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631

[2] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-6929

[3] These six companies provided data specific to count of leaks identified during each leak survey and also provided equipment information for the site in order to derive the total count of components at each site where a survey was conducted.

[4] This includes sites located in Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

well site was considered for this analysis. Following are key summary statistics from the LDAR surveys for determining the initial leak incidence rate at well pads:

- Six (6) companies providing LDAR survey results at well site locations
- 4,117 well sites
    - 1,841 Oil well sites
        - 1,164 single well sites
        - 677 multi well sites
    - 2,276 Gas well sites
        - 1,521 single well sites
        - 755 multi well sites
- 1,958,033 components surveyed
    - 95,187 components available directly from actual component count data provided for 93 sites
    - 1,862,846 estimated components based on major equipment count information for 4,024 sites using the default average component counts for onshore natural gas and crude oil production equipment as listed in 40 CFR Part 98, Subpart W Table W-1B and Table W-1C.

Utilizing the number of leaks found at the 4,117 surveyed well sites, the average initial leak incidence for all well sites was determined to be 0.4% of components surveyed. This leak incidence indicates that for sites just beginning an LDAR program – that is sites for which no organized leak detection and repair efforts had previously been made, only 4 out of every 1,000 components surveyed were found to be leaking. Table 1 below summarizes the API member company leak data.

Table 1. Summary of Initial Leak Incidence Assessment

Number of Well Sites Included in Analysis	4,117
Estimated Number of Total Components Surveyed	1,958,033
Number of Leaking Components Detected using OGI	7,838
Leak Incidence Rate	0.4%

3. EPA Leak Rate Assumptions – Subpart OOOOa Basis

In the Subpart OOOOa rulemaking, EPA relied upon various sources of information to estimate the leak incidence rate and associated emissions from leaking components. For determining the number of components that would require repair and the cost associated with repairing those components, EPA estimated that 1.18% percent of components were leaking at well sites. The leak incidence of 1.18% was obtained from Table 5 for baseline gas valves from the memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, *Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011*[5]. Note that the 1.18% percent of leaking components used by EPA to estimate the cost of repair was not directly used to estimate the baseline emissions in EPA's original analysis.

To estimate the emissions from the model well sites used to represent oil and gas facilities, EPA relied upon emission rates (kg/hr/source) for components in gas service from Table 2-4 of EPA-453/R-95-017 "*Protocol for Equipment Leak Emission Estimates*[6] *(EPA Protocol).* As described in the EPA Protocol, the values in Table 2-4 were derived from studies completed by EPA and API in the early 1990s. Appendix C of the EPA Protocol provides additional details regarding the derivation of the data in Table 2-4. Notably, Table C-1 indicates that data from only 775 total components were considered in the development of the average emission factors, of which only 368 were from oil and gas production operations.

The EPA Protocol also notes on page 5-54: *"At a process unit, the initial leak frequency can be determined based on collected screening data. If no screening data are available, the initial leak frequency can be assumed to be equivalent to the leak frequency associated with the applicable average emission factor. However, if a process unit already has some type of LDAR program in place, the average emission factor may overestimate emissions."* Table 2-4 is the source of the "applicable average emission factor" for oil and gas facilities.

4. Updated Cost-Effectiveness Values based on New Initial Leak Incidence Data

A more accurate estimate of emissions from oil and gas operations, before the implementation of an LDAR program, can be developed from new leak screening data from API member companies. This assessment consisted of the following step-wise approach, which is described in more detailed in this section:

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[5] https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OAR-2010-0505-4493&contentType=pdf

[6] https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

A. Utilize correlation equations within EPA's Leak Protocol with Table 2-4 average emission rates to establish the baseline leak incidence rate for each component type embedded within EPA's original analysis.

B. Use the derived leak incidence from Step A for each component type with the number of components in EPA's model plant to obtain the overall average leak incident rate in EPA's original analysis.

C. Re-assess the baseline emission rates for each component type using the actual observed leak incidence of 0.4% in comparison to the overall leak incidence used in EPA's original analysis identified in Step B.

D. Apply new baseline emission rates from Step C for each component in EPA's cost-effectiveness analysis for LDAR.

The EPA Protocol Table 2-4 emission rates from leaks utilized in the calculations supporting the TSD[7] were established to provide estimates of emissions from components that are not yet part of an LDAR program, and when no leak screening data is available. Section 5.3.1 of the EPA Protocol provides correlation equations that can be used to estimate leak emission rates based on the leak incidence (fraction of leaking components). For the case of oil and gas fugitive components, Table 5-7 provides correlation equations that estimate mass emission rates for different leak concentrations levels[8] (in parts per million or ppm). These emission rates are based on the average fraction of components found to be leaking during leak surveys. An example formula from Table 5-7 is shown below for gas connectors at the 10,000 ppm leak definition. All correlation equations have been provided within Attachment B for reference.

$$ALR = (0.026 \times LKFRAC) + 1.0E\text{-}05$$

Where:

ALR = Average leak rate (kg/hr per source)

LKFRAC = Leak fraction

Utilizing the formulas in Table 5-7, it is possible to back calculate the incidence rate (leak fraction) inherent to the average leak emission rates in Table 2-4. Table 2 below provides the summary of the leak incidence rates for all component types calculated using the Table 2-4 average leak emission rates with the corresponding equations at both the 10,000 ppm and

[7] https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631

[8] Table 5-7 correlation equations are stated for leak concentrations at 500 ppm, 1000 ppm, 2000 ppm, 5000 ppm, and 10000. A lower leak definition correlates to a higher incidence rate for each component type and vice versa.

500 ppm leak definition levels. To estimate the overall average leak incidence for a typical well pad, the leak incidence rates for each component were combined with the component counts and number of well pads assumed by EPA to be impacted by Subpart OOOOa in the TSD. This leads to an overall average leak incidence of 0.0165 at the 10,000 ppm leak definition and 0.0250 at the 500 ppm leak definition, versus the 0.004 observed by API members.

Table 2. Summary of Initial Leak Incidence at 10,000 ppm and 500 ppm Derived from EPA's Table 2-4 Uncontrolled Emission Factors and Table 5-7 Correlation Equations from the EPA Leak Protocol

	Derived Leak Incidence Rate (10,000 ppm leak definition)	Derived Leak Incidence Rate (500 ppm leak definition)
Valves	0.046	0.064
Flanges	0.005	0.009
Connectors	0.007	0.012
OEL	0.036	0.054
PRV	0.098	0.160
Overall Average Leak Incidence (calculated)[a]	*0.0165*	*0.0250*

a. The overall average was derived from the average leak incidence rates for each component combined with the component counts and number of well pads assumed by EPA to be impacted by Subpart OOOOa in the TSD.

In order to update the uncontrolled leak emission rates, API multiplied the average leak incidence rate for each component (as listed in Table 2 above) by the ratio of the new API average incidence rate (0.004) divided by the EPA average leak incidence rate (0.0165). The resulting updated leak emission rates for each component are provided in Table 3. Note the baseline emissions were conservatively updated using the leak incidence rates at the 10,000 ppm leak definition though OGI detects leaks at much lower leak concentrations[9]. The use of 10,000 ppm is conservative since, in this analysis, it leads to a smaller fraction of components leaking in EPA's basis (albeit at a higher mass rate). This in turn leads to the use of a smaller ratio for updating the uncontrolled leak rate.

[9] EPA states on Pages 41-42 of Subpart OOOOa TSD: *"The OGI camera is capable of viewing leaks at a 500 ppm level, and achieve similar reductions as a Method 21 monitoring program. Based on this information, we believe the expected emission reductions from an OGI monitoring and repair program falls somewhere in the 500 and 10,000 ppm range found in the Method 21 monitoring programs, but closer to the 500 ppm level."*

Table 3. EPA Leak Emission Rate and Updated Leak Emission Rates Based on Lower Observed Initial Leak Incidence

	EPA Table 2-4 Uncontrolled (kg/hr/comp)	Updated Table 2-4 Uncontrolled (kg/hr/comp)[a]
Valves	0.0045	0.0011
Flanges	0.00039	0.00009
Connectors	0.0002	0.00005
OEL	0.002	0.00048
PRV	0.0088	0.00021

a. Emission values updated using 10,000 ppm leak definition.

Next, API used the updated leak rates in Table 3 in place of the original Table 2-4 leak rates to recalculate EPA's analysis presented in its *"Modified Final_Rule_OOOOa_TSD_Section_4_-_OGI_Well_Pad_050216.xlsx"* workbook provided with the TSD, which accompanied the final rule. API also replaced the assumed 1.18% value EPA used to estimate effort to repair leaks with the actual 0.4% observed by API members. In summary, the following two changes were made to EPA's cost-effectiveness analysis:

1. Replace the Table 2-4 average emission rates with the updated leak emission rates provide in Table 3 that reflect the lower overall observed leak incidence rate observed by operators.
2. Replace EPA's assumed 1.18% leak incidence for repairs with the 0.4% leak incidence derived from actual LDAR survey data.[10]

The "Model Plant 2012" tab of EPA's workbook provides cost-effectiveness estimates for implementation of LDAR at quarterly, semiannual, and annual frequencies. The tables in Attachment A of this document provide comparison of the cost effectiveness considering the updated values reviewed by API and described above versus the original values used by EPA. As the first table in Attachment A shows, the updated cost-effectiveness values are approximately 4 times higher than the values EPA originally estimated. As this data clearly shows, if the more accurate representation of initial (uncontrolled) leak incidence from API member data were available at the time of the original rulemaking, LDAR would not have been considered cost-effective, even at an annual frequency.

No other changes were made to the cost-effectiveness calculations in this assessment, even though API has commented previously on numerous issues with the overall approach and

[10] This update has the effect of lowering EPA's cost-effectiveness estimate because EPA directly used the leak incidence of 1.18% to estimate time for repair of components.

analysis conducted for the original rulemaking as it relates to LDAR. As API outlined in our December 4, 2015 comments during the rulemaking, other key issues include:

- EPA underestimated the programmatic costs to implement an LDAR program for oil and gas sites.
- EPA applied incorrect values for emissions reductions that would occur for different leak frequencies (i.e., annual, semi-annual, quarterly) and the actual reductions are less than EPA assumed.
- EPA overestimated component counts for the model plant gas and oil well sites, thus overstating baseline emissions.

If the above issues were also addressed and corrected, the result would be to further increase the cost-effectiveness ($/ton) value associated with applying LDAR. For instance, applying the correct 50% control factor for semi-annual LDAR instead of the 60% used by EPA would increase the Cost of Control ($/ton) values for semi-annual LDAR by a factor of 1.2. This analysis supports justification for a reduced survey frequency at well sites from semi-annual to annual.

ATTACHMENT A

LDAR Cost Effectiveness Estimates

(Updated and Original EPA Multi-Pollutant Values)

API Updated Cost-Effectiveness Analysis

Model Plant 2012 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$759	$1,094	$971	0.53	0.148	$1,027	$912	$3,696	$3,279	1,782	495	$2,539,249	$3,661,461	$3,248,433
Oil Well Sites (GOR < 300)	6,812	$759	$1,094	$1,067	0.12	0.032	$4,574	$4,458	$17,051	$16,619	815	219	$5,169,565	$7,454,236	$7,265,331
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$759	$1,094	$1,033	0.27	0.073	$2,053	$1,937	$7,504	$7,081	2,486	680	$7,080,452	$10,209,633	$9,633,275
All Wells Weighted Averages							**$2,098**	**$1,982**	**$7,648**	**$7,226**					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$801	$1,837	$1,652	0.80	0.222	$1,150	$1,034	$4,137	$3,720	2,673	743	$2,679,903	$6,147,634	$5,528,092
Oil Well Sites (GOR < 300)	6,812	$801	$1,837	$1,796	0.18	0.048	$5,119	$5,004	$19,086	$18,654	1,222	328	$5,455,917	$12,515,746	$12,232,388
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$801	$1,837	$1,745	0.40	0.109	$2,298	$2,182	$8,400	$7,976	3,730	1,020	$7,472,651	$17,142,089	$16,277,552
All Wells Weighted Averages							**$2,348**	**$2,232**	**$8,561**	**$8,138**					
Quarterly Monitoring - Multi Pollutant															
Gas Well Sites	3,346	$885	$3,323	$3,076	1.07	0.296	$1,560	$1,444	$5,613	$5,196	3,564	991	$2,961,210	$11,119,981	$10,293,924
Oil Well Sites (GOR < 300)	6,812	$885	$3,323	$3,268	0.24	0.064	$6,945	$6,829	$25,893	$25,461	1,630	437	$6,028,620	$22,638,766	$22,260,955
Oil Well Sites w/ Associated Gas (GOR > 300)	9,330	$885	$3,323	$3,200	0.53	0.146	$3,118	$3,002	$11,395	$10,972	4,973	1,361	$8,257,050	$31,007,000	$29,854,284
All Wells Weighted Averages							**$3,185**	**$3,069**	**$11,614**	**$11,191**					

While API outlined additional issues with the overall approach for estimating costs and benefits of implementing LDAR in our December 4, 2015 comments, only the following changes were made in this analysis:
1) Replaced the Table 2-4 emission rates with the updated leak emission rates that reflect the lower observed leak incidence rate, and
2) Replaced EPA's assumed 1.18% leak incidence for repair costs with the 0.4% leak incidence derived from actual LDAR survey data observed by operators.

EPA 's Original Cost Effectiveness (Model Plant 2012 Sheet in "Final_Rule_OOOOa_TSD_Section_4_-_OGI_Well_Pad_050216.xls")

Model Plant 2012 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

					Nationwide Emission Reductions[5]		*Methane Cost of Control*		*VOC Cost of Control*		*Nationwide Emission Reductions*		*Total Nationwide Costs*		
Category	*Number of New Sources[1]*	*Capital Cost ($)[2]*	*Annual Cost ($/yr)[3]*	*Well Site Annual Cost w/Savings ($/yr)[4]*	*Methane (Tons/yr)*	*VOC (Tons/yr)*	*w/o Savings ($/Ton)*	*w/ Savings ($/Ton)*	*w/o Savings ($/Ton)*	*w/ Savings ($/Ton)*	*Methane (Tons/yr)*	*VOC (Tons/yr)*	*Capital Cost*	*Annual Cost w/o savings*	*Annual Cost w/ Savings*
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	*3,346*	*$759*	*$1,318*	*$809*	*2.20*	*0.611*	*$300*	*$184*	*$1,079*	*$662*	*7,355*	*2,044*	*$2,539,249*	*$4,411,155*	*$2,706,234*
Oil Well Sites (GOR < 300)	*6,812*	*$759*	*$1,318*	*$1,204*	*0.49*	*0.132*	*$1,335*	*$1,219*	*$4,977*	*$4,545*	*3,364*	*902*	*$5,169,565*	*$8,980,511*	*$8,200,737*
Oil Well Sites w/ Associated Gas (GOR > 300)	*9,330*	*$759*	*$1,318*	*$1,063*	*1.10*	*0.301*	*$599*	*$483*	*$2,190*	*$1,767*	*10,263*	*2,808*	*$7,080,452*	*$12,300,083*	*$9,920,962*
All Wells Weighted Averages							***$612***	***$496***	***$2,232***	***$1,810***					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	*3,346*	*$801*	*$2,285*	*$1,521*	*3.30*	*0.917*	*$347*	*$231*	*$1,247*	*$830*	*11,032*	*3,067*	*$2,679,903*	*$7,647,023*	*$5,089,641*
Oil Well Sites (GOR < 300)	*6,812*	*$801*	*$2,285*	*$2,114*	*0.74*	*0.199*	*$1,543*	*$1,427*	*$5,752*	*$5,319*	*5,046*	*1,353*	*$5,455,917*	*$15,568,296*	*$14,398,635*
Oil Well Sites w/ Associated Gas (GOR > 300)	*9,330*	*$801*	*$2,285*	*$1,903*	*1.65*	*0.451*	*$693*	*$577*	*$2,531*	*$2,108*	*15,395*	*4,212*	*$7,472,651*	*$21,322,989*	*$17,754,307*
All Wells Weighted Averages							***$708***	***$592***	***$2,580***	***$2,157***					
Quarterly Monitoring - Multi Pollutant															
Gas Well Sites	*3,346*	*$885*	*$4,220*	*$3,201*	*4.40*	*1.222*	*$480*	*$364*	*$1,726*	*$1,310*	*14,710*	*4,089*	*$2,961,210*	*$14,118,757*	*$10,708,915*
Oil Well Sites (GOR < 300)	*6,812*	*$885*	*$4,220*	*$3,991*	*0.99*	*0.265*	*$2,136*	*$2,020*	*$7,964*	*$7,532*	*6,728*	*1,805*	*$6,028,620*	*$28,743,865*	*$27,184,318*
Oil Well Sites w/ Associated Gas (GOR > 300)	*9,330*	*$885*	*$4,220*	*$3,710*	*2.20*	*0.602*	*$959*	*$843*	*$3,505*	*$3,081*	*20,527*	*5,616*	*$8,257,050*	*$39,368,800*	*$34,610,558*
All Wells Weighted Averages							***$980***	***$864***	***$3,572***	***$3,150***					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on date from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, initial activities planning, notification of initial compliance status, and purchase of M21 monitoring device.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $4/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semi-annual OGI camera monitoring and 80% reduction with quarterly OGI camera monitoring.